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Abstract

To allow storage of large masses of gas, the maximum admissible pressure in a gas cavern must be high, but it must be not too high in order to prevent gas leakage. The empirical approach consists of calculating the weight of the overburden (the "vertical stress") and selecting a maximum pressure, which is 80-85% of the vertical stress. In addition, a Mechanical Integrity Test (MIT) must be performed. This approach is robust and is supported by decades of safe operation of dozens of gas caverns worldwide. Over the past 20 years, research, much of which is supported by the Solution Mining Research Institute (SMRI), has been performed to obtain better insight in the mechanisms of gas leaks. The research suggests that the empirical approach is basically sound; however, it must be completed by numerical computations that take into account the geological, geomechanical, geometrical and operational conditions of the actual cavern.

Key words: Caverns for Gas Storage, Maximum Gas Pressure, Rock Mechanics

Introduction

The amount of natural gas that can be stored in a salt cavern depends essentially on the values of the maximum and minimum pressures of the gas. More gas can be stored when the maximum admissible pressure is higher, but too high a gas pressure can lead to gas leakage.

The traditional approach consists of selecting a maximum pressure such that no fracking of the salt-rock mass can occur. For this reason, the maximum gas pressure must be smaller than the least compressive stress in the rock-salt mass. The least compressive stress is equal to or smaller than the vertical stress, which can be assessed readily through density logs and/or frac-tests.

Because it is known that the cement behind the last casing often is weaker than the rock formation, a margin of safety must be managed, with the maximum gas pressure is around 80%-85% of the vertical stress. In addition, a tightness test (the Mechanical Integrity Test, MIT) must be performed before commissioning.

This approach is used commonly. However higher values of the maximum pressure are selected sometimes, especially when dimensioning new caverns in a gas-storage field where a large amount of prior experience is available.

This traditional approach was revised recently, especially as research supported or prompted by the Solution Mining Research Institute (SMRI) proved that, on one hand, several mechanisms may increase salt permeability during cavern operation and that, on the other hand, fast injections or withdrawals significantly modify the state of stresses at the vicinity of the caverns.

1. Avoiding fracking

1.1. *Fracturing of the uncased part of the cavern*

The origin of the empirical approach can be found in the experience gained in gas- or oil-well operation. It is known that a fracture can be created in the unlined part of a borehole when a sufficiently high fluid pressure is applied at the wellhead. This technique is used for stimulating production wells or for measuring in-situ stresses (frac-test). In a salt cavern, the fluid pressure certainly must be smaller than the “fracture breakdown pressure” — i.e., the pressure at which such that a fracture is created, even smaller than the “shut-in pressure”.

1.2. *Breakdown pressure and shut-in pressure*

During a frac test in a salt formation, a borehole interval is isolated between two inflatable tight packers, and brine (or gas) is pumped in the interval. Rock fractures when the breakdown pressure is reached (Fig. 1). Then, pumping is halted, and pressure stabilizes at a level called the fracture-propagation pressure (or shut-in pressure). The difference between the breakdown pressure and the shut-in pressure is called “rock tensile strength”; in the case of a salt formation, this strength is typically 1-3 MPa (150-450 psi).

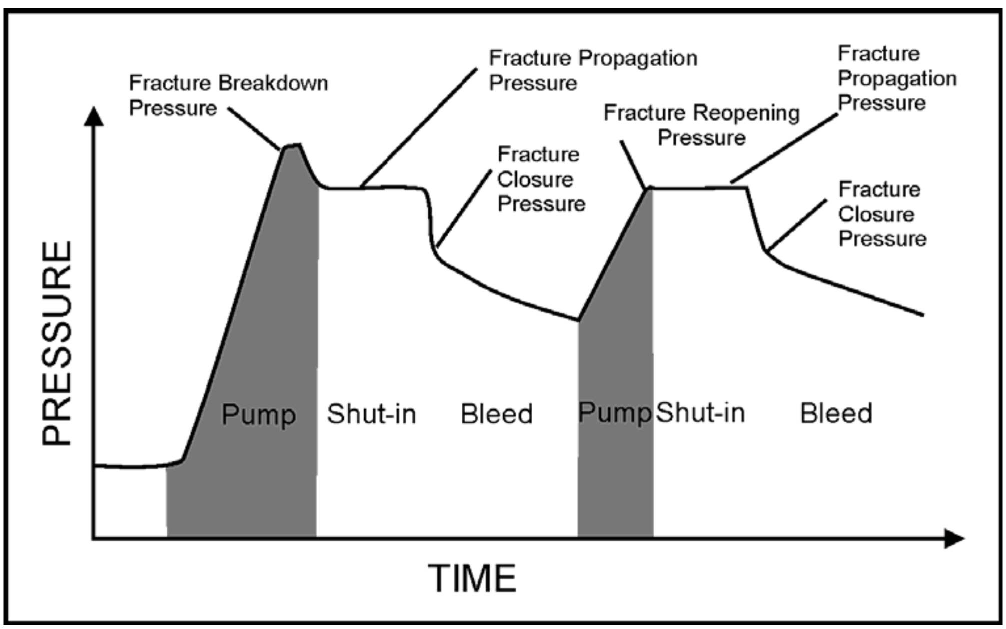


Figure 1. Simplified pressure-time chart characteristic of a hydraulic test [Bell, 1996 (cited in Horwarth and Wille, 2009)]

Three principal stresses can be defined at any point in the rock mass. It generally is accepted that, in a virgin salt formation, one of these three stresses, σ_v, is vertical. The two other stresses, $\sigma_H \geq \sigma_h > 0$, are horizontal. (Compressive stresses are negative.) The shut-in pressure is a measure for the least compressive principal stress — i.e., it is equal to σ_h or σ_v Rummel et al. (1996), Horvath and Wille, (2009, p. 88). At least when rock behavior is considered as elastic, this phenomenon is well accounted for by Fracture Mechanics.

1.3. Vertical stress and overburden pressure

The vertical stress, σ_v, (also called geostatic pressure, lithostatic pressure or overburden pressure) is, by definition, larger than or equal to the least compressive stress (the shut-in pressure). In principle, due to the visco-plastic nature of salt, the three principal stresses should be equal, and the shut-in pressure is also the vertical stress: "*In depth below 500 m isostatic stress condition* $(\sigma_v = \sigma_H = \sigma_h)$ *can be assumed in salt rock formations due to the creeping behavior of salt rock*" (Klafki et al., 1998, p. 276). However, tests suggest that, in some cases, this "isostatic" assumption is wrong, and the vertical stress is smaller or larger than the horizontal stress. Equilibrium equations suggest that the vertical stress results from the weight of the overlying ground. According to Horwarth and Wille (2009), the weight of the overburden can be measured through "*density determination from rock samples, analysis of litho-density logs, hydraulic fracture tests and borehole gravity measurements …The pressure determined by fracture tests (the so-called "shut-in pressure") is thought to represent the [least compressive] principal stress. However fracture tests have been observed to provide formation pressure values about 5% higher* [than other methods]" (p. 84). Also Klafki et al. (1998): "*in situ measured primary stresses are higher than calculated from rock densities*" (p. 276). In conclusion, Horwarth and Wille (2009) state that "*density logs have proved … to supply data of sufficient quality".*

1.4. Conclusion

Maximum gas pressure must be smaller than the vertical stress, which can be assessed through density logs and/or frac-tests. However, some safety margin must be left. There are two reasons for this: on one hand, the least compressive stress is not always the vertical stress — even if they often are equal; on the other hand, the cement behind the last steel casing often is weaker than the rock mass itself.

2. A weak point: The cement

2.1. The cement

The cement at the vicinity of the last cemented casing shoe (i.e., at the top of the unlined part of the well) may be as strong as the rock formation. However, cement is an engineered material and its tightness basically depends on the quality of the cementing job. The cemented annular space includes two interfaces, between the cement and the casing steel, and between the cement and the rock mass. These interfaces are possible weak points, especially in gas storage caverns, as the cement shrinks and expands alternatively when large pressure swings are applied to the cavern gas. For these reasons, the cemented part of the well often is weaker than the rock formation itself.

2.2. Factors important for cement quality

Cement integrity results from: the properties of the rock mass; the quality of the cementing job; the well architecture (i.e., the number and the length of the cemented casings); the nature of the stored products; and the pressure and pressure changes of the stored fluids.

> Tight and plastic rock formations, such as salt and clay, can have a very favorable effect in that they naturally creep and tend to tighten around the well, improving the bond between the cement and the casing.
>
> Since the origin of oil drilling, progress has been made in cementing workmanship. In the case of Texas, Nicot (2009) mentions: use of centralizers (1930); caliper surveys (1940); tagging of the

cement plug, introduction of improved cement additives adapted to temperature, pressure, and chemical specific conditions (1940); and improvement of the quality of material used in well construction. Nicot also outlines the promulgation by the Texas Rail Road Commission of specific plugging instructions (1934, 1967), promulgation of the Drinking Water Act, publication of API national standards (starting 1953), and increased scrutiny by the State (after 1983). Effective tools allow assessment of the quality of the cement (CBL/VDL, high frequency measurements, etc.). However, appraising the quality of a cement job is not an easy task. Experience proves that cement quality can be scattered. For salt cavern wells, with casing diameters larger than in oil fields, Kelly and Fleninken (1999) proposed the notion of a Cement Evaluation Logging Program to minimize uncertainties.

Gaseous products raise more difficult problems than liquid products. On one hand, they are less viscous, and the gas flow-rate is faster; on the other hand, gases are much less dense than liquids. When a leak appears, gas pressure remains almost constant along the leak path, and gas pressure is able to fracture rock formations at shallow depth where geostatic pressure is small (Fig. 2).

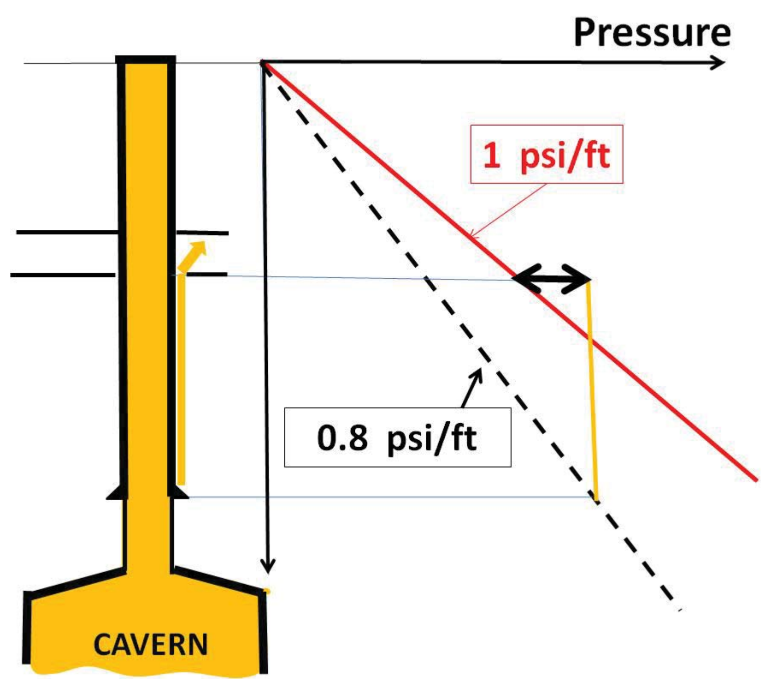


Figure 2. Illustration of a gas leak: the vertical pressure gradient is 1psi/ft, and the maximum pressure gradient is 0.8 psi/ft

Well architecture is important as well In Texas, for instance, two cemented casings must be anchored to the salt formation, as salt domes often are capped by a permeable zone (cap-rock), which is a weak point from the perspective of tightness (Fig. 3). In Europe, the state of the art consists of equipping the wellbore with an inner tubing. A packer (sometimes two) is (are) placed at the bottom of the annular space, slightly above the casing shoe. The annular space is filled with non-corrosive water, and gas production is monitored at the top of the annular space. Such architecture minimizes the detrimental effects of large pressure and temperature swings on the cemented casing.

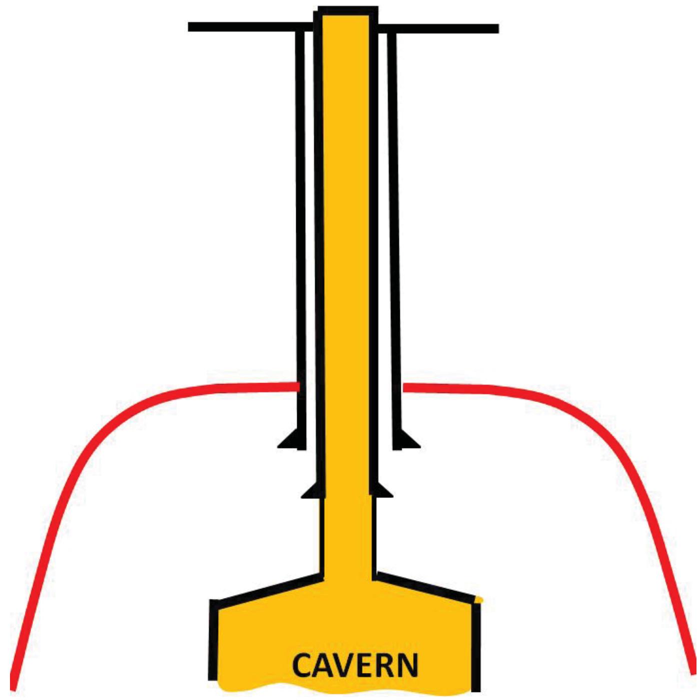


Figure 3. Two cemented casings anchored to the salt formation

The maximum pressure for gas and pressure-change rates obviously are important factors, as well.

3. The empirical approach: Pressure gradient

3.1. A margin of safety

The empirical, or pragmatic, approach consists of estimating the weight of the overburden (vertical stress") at cavern-shoe depth using density logs and selecting a maximum admissible pressure (80-85% of the vertical stress). This margin of safety takes into account such factors as uncertainties and possible cement weaknesses.

This method is robust, as it relies on simple mechanical principles and reliable measurements (density logs). In addition, performing frac-tests can be useful, as they provide the value of the least compressive stress (shut-in pressure). It must be kept in mind, however, that the shut-in pressure is an upper bound for the least compressive stress. The maximum operating pressure must be re-assessed in the (rare) case that the shut-in pressure is smaller than the vertical stress.

Research on cementation (its evolution with time, fracturing mechanisms, in-situ stress measurements) must be fostered, but it is dubious that this research affects in the short term the rule mentioned above, which relies primarily on experience.

3.2. Assessing rock-mass density

Determining the actual density of the rock formations above the caverns is important in such a context. Pereira (2012) states that "*typical values of the overburden stress gradient may range from a low of 21.5 kPa/m (0.92 psi/foot) for a domal salt overlain by soft sediments, to a high of about 0.26 kPa/m (1.14 psi/foot) for a bedded salt largely overlain by dense limestone and anhydrite layers*" (p. 6-2; see also Schreiner et al., 2010). Misinterpretation is possible, as explained by Rokahr et al. (2000). Before the Etzel test, described below, it was assumed that the lithostatic gradient was 24.1 kPa/m (1.06 psi/ft).

Additional investigations from a new reference borehole and three existing boreholes led to a revised value of 20.4 to 21.1 kPa/m (0.9 to 0.93 psi/ft) — a significantly smaller figure. Lithodensity logs are convenient to use. Density measurements in the laboratory also can be used; they provide a lower bound of the in-situ rock density, which errs on the safe side.

3.3. Pressure gradient

Density, which is a site-specific notion, must be measured on a case-by-case basis. Regulators, however, often prefer rules that can be applied state-wide uniformly and that a maximum pressure gradient, or $dP_{\max} / dz$, is defined. This is the ratio between the maximum admissible pressure at the casing shoe and the casing-shoe depth. This pressure gradient must be smaller than the vertical pressure gradient (i.e., vertical stress divided by depth). For example, when the selected maximum pressure gradient is 18 kPa/m (0.8 psi/ft), the equivalent density is (18 000 Pa/m)/ 9.8 m/s^2 = 1835 kg/m^3, which certainly is smaller than the actual density of the overburden. This criterion is less general than the criterion mentioned above. In the example above, it is more severe than the 80%-of-the-vertical-stress criterion, when the actual density of the overburden is larger than 2160 kg/m^3.

This rule generally is accepted in the U.S. For instance, the Texas Administrative Code § 3.97(k)(2) (2007) stipulates that "*The maximum operating pressure at the casing seat shall not exceed 0.85 psi/ft of depth*". In 2003, the Kansas Department of Health & Environment stated that "*The maximum allowable operating pressure for underground natural gas storage wells shall not exceed 0.75 psi/ft*", or 17 kPa/m (Poyer and Cochran, 2003, p. 199). In a report prepared for the SMRI, Pereira (2012) indicates that "*the maximum regulated pressure gradient is 0.9 psi/ft (20.4 kPa/m) in Louisiana and Mississippi and 80% of fracture pressure or 0.8 psi/ft in Canada". "In France, Germany and UK, the maximum admissible pressure is "negotiated case by case*" (p. 6-14).

3.4. Lessons drawn from experience

Most cavern designs meet this criterion. Rummel et al. (1996) describe frac tests performed at Krummhörn, Germany, where three caverns had been leached out: casing-shoe depths were about 1500 m and the selected maximum pressure was 27 MPa — a 18 kPa/m (0.8 psi/ft) gradient. Itsvan (1998) mentions a cavern under construction in Kansas in which the maximum gas-storage pressure was 1760 psi, a gradient of 0.88 psi/ft at 2000 ft. Bruno and Dusseault (2002) discussed the case of pressure limits for thin bedded salt caverns: the maximum pressure must not exceed the estimated fracture pressure for the weakest lithology (margins of safety not specified). Chabannes (2005) mentions a cavern at Egan (Jennings salt dome, Louisiana) in which the maximum pressure gradient was 0.9 psi/ft. Colcombet et al. (2008) describe the Carriço Project, in which the maximum pressure was 18 MPa and the last cemented casing was around 1000 m (an 18-kPa/m gradient). Schweinsburg and Schneider (2010) present a cavern at Etzel, Germany, where the casing-shoe depth is 1150 m and the maximum gas pressure is 20 MPa — a 17-kPa/m (0.75 psi/ft) gradient (More recently, 20.8 MPa was accepted). Hoelen et al. (2010) dimensioned a four-cavern project at Zuidwending in the Netherlands. The caverns were to be operated between 9 MPa and 18 MPa, and the casing-shoe depth was 980-1028 m (a gradient of $\approx 18\ \mathrm{kPa/m}$). In China, Ban Fansheng et al. (2010) indicate "*gas injection-production pressure is … 17 MPa to 32 MPa for gas storage constructed in about 2000 –m deep salt bed, and from 7 MPa to 17 MPa in about 1000-m deep salt bed*" (p. 190) — a maximum gradient of 16 to 17 kPa/m. McLeod et al. (2011) describe a nine-cavern gas storage at Aldbrough, Yorkshire, in which the casing-shoe depth was 1500 m and the maximum pressure was 27 MPa (a 15 kPa/m gradient). Bernhardt and Steijn (2013) discussed two cavern projects at Nüttermoor, Germany. There, the cavern-roof depths and maximum pressures at the casing shoe were 1020 m and 945 m and 17 MPa and 16 MPa, respectively. In Germany, Wagler and Draijer (2013) discuss a nitrogen storage project in which the last casing-shoe depth is 648.2 m. The maximum pressure initially considered was 122 bars (an 18.8 kPa/m or 0.83 psi/ft gradient). Installing a new casing at a depth of 984 m led to a maximum pressure of 177 bars (an 18 kPa/m or 0.8 psi/ft gradient). Fawthrope et al. (2013) discuss construction of eight caverns at Holford, Cheshire, in which the casing-shoe depth was $\approx 550\ \mathrm{m}$ and the maximum pressure was 10 MPa, an 18 kPa/m gradient.

3.5. Higher values of the maximum operating pressure

It is tempting to select a maximum operating pressure larger than those suggested above (80 to 85% of the overburden pressure) to increase the amount of gas that can be stored in the cavern. For instance, Igoshin et al. (2010) describe three gas-storage caverns under construction at Kaliningrad, Russia. The cavern volume is 400,000 m^3, and the maximum and minimum admissible cavern pressures are 18 MPa and 5.2 MPa, respectively. There, cavern depth is from 880 to 1020 m (casing depth not provided), making the gradient at cavern top equal to 20 kPa/m. Schreiner et al. (2004), based on pneumatic tests, suggest a storage-pressure gradient of 19-20.5 kPa/m or 0.84-0.91 psi/ft (around 85% of the geostatic pressure) for bedded salt formation and 18 kPa/m in domal salt, "*as densities are lower*".

It is clear that the risk of a significant leak is greater when fluid pressure is higher, and that must be considered carefully. A high admissible pressure can be accepted when a large amount of information is available to increase confidence in the outcome.

For instance, Arnold et al. (2014) mentioned that: "*the storage site Bernburg is operated since the early 1970ies* (sic) …*the rock mechanical dimensioning of caverns has been developed and enhanced continuously using comprehensive investigations … the most recently approved rock mechanical dimensioning includes a pmax of 100 bars casing shoe depth is 490 m. (gradient 2.04*)" [20.4 kPa/m or 0.9 psi/ft] (p. 138). Johansen (2010) describes the Torup gas storage in Denmark. When the first caverns were created in 1981, the maximum pressure gradient was 17.5 kPa/m (0.77 psi/ft). When the last cavern was leached out in 1992, the gradient was 18.4 kPa/m (0.81 psi/ft). In these two cases, the increase in maximum admissible pressure was vindicated by the experience drawn from decades of satisfactory operation of existing caverns.

In our opinion, setting the maximum admissible pressure above the standard value (80 to 85% of the overburden weight) must be justified through a specific "safety file" that contains discussions of such topics as local sensitivity of the storage site (for instance, noting that a layer of salt or plastic clay several hundreds of meters above the cavern roof is favorable, a permeable cap rock within a small distance from the cavern roof is unfavorable), along with density files, results of the MITs, etc.

4. The empirical approach: Tightness tests

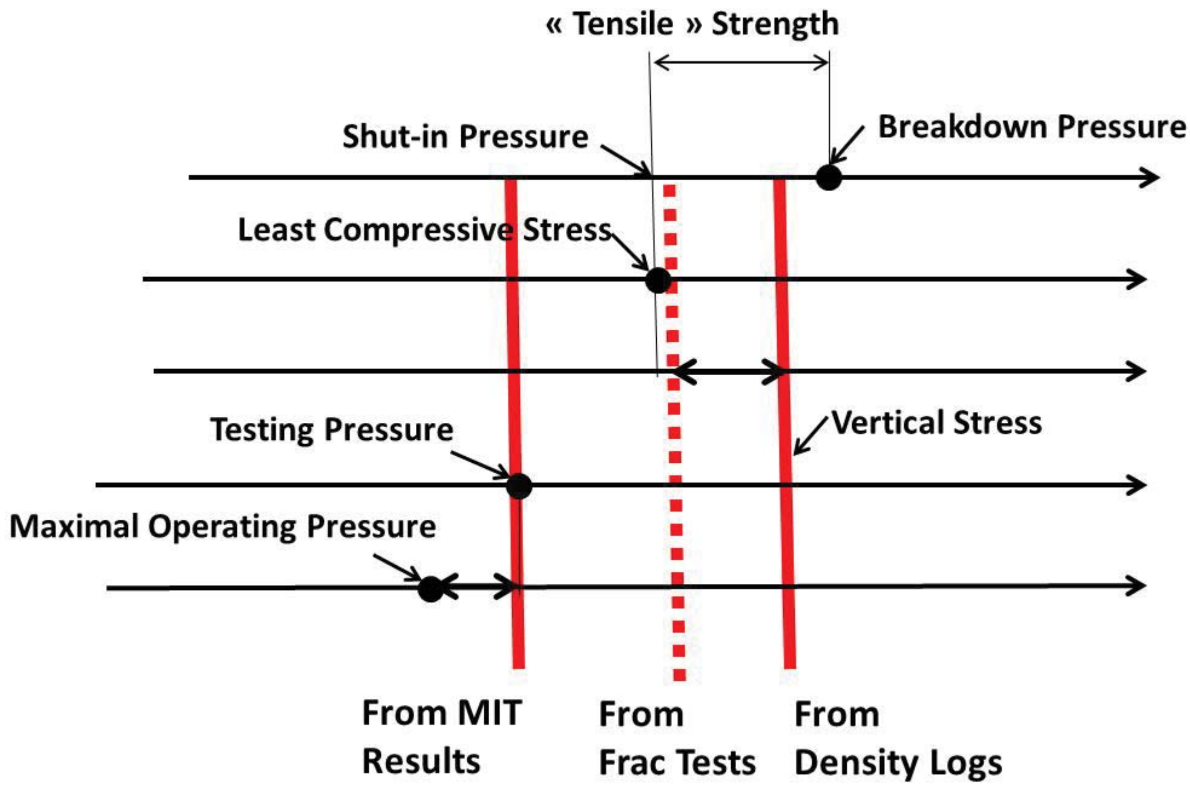
Hundreds of natural gas caverns have been operated worldwide during decades. Only a small number of leaks are known. The most dramatic leaks (Mont-Belvieu, Hutchinson) originate in the failure of a steel casing rather than in the cement itself. Experience proves that the rule mentioned above is robust. However, it remains empirical, as it is based on the analysis of virgin stresses in the rock mass, a notion that implies some uncertainty, and it does not address the second problem mentioned in the introduction —i.e., cement tightness.

4.1. Tightness tests

Cementing remains a difficult job, and it is recognized worldwide that before commissioning a cavern, a tightness test (MIT) must be performed. A tightness test consists of increasing cavern pressure to the maximum operating pressure (or slightly more) and monitoring cavern evolution. The best method consists of lowering a nitrogen column to develop a brine-nitrogen interface below the last casing shoe and monitoring the interface location over a couple of days: too fast an interface rise is a sign of poor tightness. Monitoring wellhead pressures provides additional information. When the cavern neck is not consistent, lowering a light hydrocarbon column (instead of a nitrogen column) can provide good results. In some countries, tightness tests are performed periodically during the entire operating life of a cavern. Acceptance criteria have been proposed [for instance, Crotogino (1994), Thiel (1993)]. In most cases, the results of the test performed before commissioning a cavern satisfy these criteria. When they do not, various techniques allow identification of the weak zones of the cement column and repair of the well before performing a second tightness test (see, for instance, McLeod et al., 2011).

4.2. Testing pressure

The testing pressure must be selected carefully. It must be equal to or larger than the maximum operating pressure (Fig. 4). Many companies consider that the testing pressure must equal the maximum operating pressure (Quintanilha de Menezes et al., 2001), as testing the well above the operating pressure can be harmful for future well integrity. Conversely, other companies prefer selecting a higher pressure, which provides additional confidence. One advantage of this second option is that, after several years of satisfactory operation, this makes an increase in maximal operating pressure easier, as the cavern was tested for higher pressures from the beginning.



operating pressure $\leq$ testing pressure < least compressive stress (shut-in pressure) $\leq$ vertical stress

Figure 4. The maximal operating pressure must be smaller than the least compressive stress, which is smaller than (or equal to) the vertical stress. [The vertical stress can be assessed reliably through density logs. (Shut-in pressure can be measured through frac-tests; however, their results may lead to an overestimation.) Testing pressure must be a fraction of the vertical stress. A successful MIT proves that both the rock mass and the cement are tight.]

5. Recent research

The theoretical considerations that support the empirical approach rely on several assumptions. On one hand, the mechanical behavior of the rock mass is assumed to be elastic: when the maximum fluid pressure is reached in the cavern, the salt formation has been given enough time to “forget” the effects of the past history of cavern pressures. On the other hand, it is assumed that, before the breakdown pressure is reached, salt permeability remains equal to its virgin value, generally very small. Several research projects, many supported by the SMRI, have led to a revision of these notions.

5.1. The Etzel Test

The Etzel test was performed in 1990 (Rokahr et al., 2000). The pressure of the K102 brine-filled cavern was increased incrementally through brine injection. When the test gradient became larger than 19 kPa/m, an increase of the cavern compressibility was observed, a clear sign of brine leaks. (The cavern compressibility is the volume of brine to be injected in a cavern to increase its pressure by 1 MPa.) After the gradient pressure became larger than 21.9 kPa/m (0.968 psi/ft), evidence of large leaks (rapid pressure drops) became clear. These facts tend to prove that cavern pressure must remain smaller than the geostatic pressure. (In this example, the vertical stress was 20.4 to 21.1 kPa/m, see Section 3.2).

This test has been discussed by several authors [including Hauck et al. (2001) and Lux et al. (2006)]. Djizanne et al. (2012) suggest that the history of pressures in the cavern can explain the early fracturing observed during the test. The test was preceded by a long period during which cavern pressure was low, and a viscoplastic decrease of the deviatoric stress (i.e., the gap between the three principal stresses) took place. The rapid increase of pressure during the test generated a transient stress distribution such that one of the main stresses was less compressive than it had been before the cavern was created, making fracturing easier. When this approach is accepted, cavern tightness is a function not only of the cavern pressure, but also of the history of cavern pressure.

5.2. Salt permeability (Durup's and Fokker & Kenter's tests)

Durup (1994) increased brine pressure incrementally in a wellbore over a one-year-long test. A minute brine leak was observed even when the pressure was low, and Darcy's law applied. (The leak rate was proportional to the pressure increase.) Fracturing took place when brine pressure was significantly higher than geostatic pressure. This result was more favorable than what had been observed at Etzel, as a tightness test performed in a wellbore is more compelling (The pressure-drop rate following the onset of a leak is faster.) than a test performed in a full-size cavern, which is much more compressible than a wellbore. In fact, Durup's test was much longer than Etzel's test, and it is likely that more time was left to restore the virgin state of stresses in the rock mass.

Kenter et al. (1990) and Fokker (1995) proved that a significant increase in the permeability of a salt sample, due to the onset of a diffuse micro-fracturing, can be observed when the pressure of the permeating fluid is slightly smaller than the least compressive stress in the sample. This result was a breakthrough, as it suggested that rock permeability can increase even when gas pressure is lower than the least compressive stress at the cavern wall, which questions the standard approach for determining the maximum admissible pressure. Such an observation was confirmed by laboratory tests performed by Bérest et al. (2001). In other words, for rock salt, the classical approach inspired by Fracture Mechanics should be revised: before the onset of fracturing proper, which was observed by Durup (1994) during his test and by Rummel et al. (1996) or Doe & Osnes (2006) during frac tests, micro-fracturing develops progressively at cavern walls, leading to a large change in permeability (i.e., the onset of a "secondary permeability").

5.3. A new approach of the maximum admissible pressure: "infiltration" or "penetration" zone

It soon was recognized by the SMRI that these new results called for re-interpretation of the standard criteria used for determining the maximal admissible pressure and the SMRI sponsored a study performed by Rokahr et al. (1997, 1998). The authors recognize that an "infiltration" zone may appear when gas pressure is larger than one of the two tangential stresses at cavern wall. More generally, this zone increases when gas pressure in the infiltration zone (Infiltration is assumed to be governed by Darcy's law.) is larger than the two compressive stresses perpendicular to the fluid-flow direction. The authors propose that the cavern be operated in such a way that the infiltration zone remains confined inside a "safety zone" in which the gas pressure is significantly smaller than the compressive stresses in the rock mass. They discuss the influence (for a given maximum admissible pressure) of such factors as the virgin state of stress, the shape of the cavern roof, and the vertical distance from the casing shoe to the cavern roof. It must be mentioned that, in this study, the authors discussed "seasonal storage" only: no fast injection or withdrawal was considered, and the onset of "thermal" stresses due to gas temperature changes was not discussed.

Lux et al. (2004) proposed a slightly different criterion: "*Two main components have to be sufficiently larger than the cavern inside pressure … in a sufficiently large salt rock mass*" (p. 98). These small differences reflect a difficulty: it is easy to express an infiltration criterion at the cavern wall as one of the principal stresses equals fluid pressure (i.e., gas pressure in the cavern), but it is more difficult to define a criterion inside the rock mass, as assumptions must be made on the development of the secondary permeability.

In 2007, Brouard et al. proposed the "*no, or limited, effective tensile zone*" criterion: cavern pressure minus rock strength must not be larger than the least compressive stress at cavern wall. This criterion apparently is similar to the standard definition of the breakdown pressure during a frac-test. A large difference is that, in this criterion, it is not the virgin stress but, rather, the actual stress that is concerned — the latter can be significantly smaller than the former, as salt does not behave as an elastic material.

Haq et al. (2010) adopted similar views, and in the same spirit, Minkley et al. (2011) propose that the extent of this "penetration zone" be less than 10% of the pillar width between two neighboring caverns. However, they take into account the accumulated dilation to define this zone (see Section 5.5).

5.4. The significance of thermal stresses

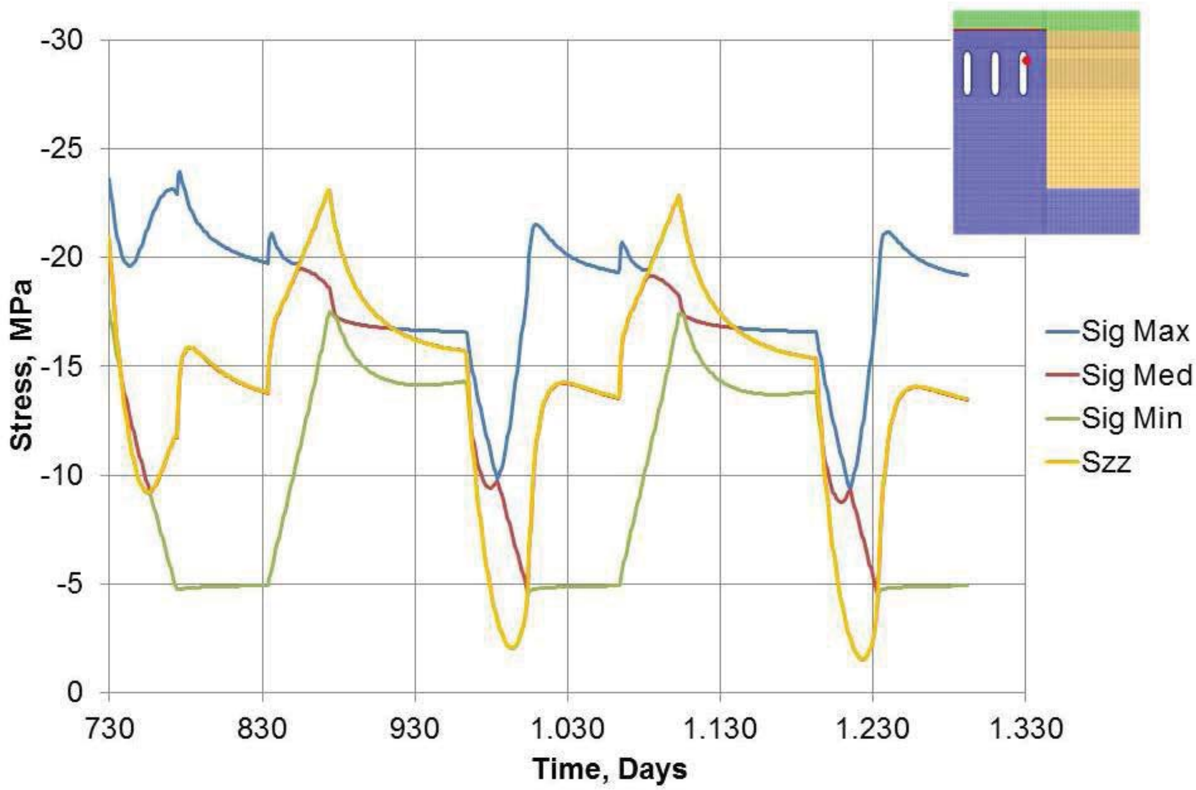


Figure 5. "Principal Stress Components at the Assessment Point in the Roof Section of the Border" (Zapf, 2014).

Prompted by the 2003 directive of the European Union (Dresen and Lux, 2011) new European operating modes of gas caverns appeared in which gas pressure rates are much faster than what they were when only seasonal modes were considered. In this new context, the thermodynamic behavior of the stored gas has important consequences for the mechanical behavior of the cavern. It was known that gas withdrawal generates large compressive stresses at the cavern wall, favoring rapid creep closure and the possible onset of dilation. However, *fast* gas withdrawal generates additional tensile (thermal) stresses at the cavern wall. To a certain extent, these additional stresses are favorable, as they mitigate the "mechanical" effect of decompression — as opposed to the "thermal" effect of decompression. When withdrawal is *quite fast*, these "thermal" stresses are larger than the "mechanical" stresses, and there is a risk of fracturing at the cavern wall. This topic was addressed by many authors, including Nieland and

Ratigan (2006) and Bérest et al. (2012). More to the point, when maximum admissible pressure is discussed, fast gas injection generates additional compressive stresses at the cavern wall; they mitigate the “mechanical” effects of injection — i.e., the onset of tensile effective stresses, and the risk of micro-fracturing and an increase in rock mass permeability. However, this favorable effect is not sustained: when injection stops, the gas temperature gradually slows, and additional stresses vanish.

Note that, in such a context, the coefficient of the thermal expansion of salt plays an important role. (Thermal stresses are proportional to this coefficient.) In the past, not much attention was paid to this coefficient, which generally is considered to be $\alpha_{salt} \approx 4\times10^{-5}$ / °C. It is important to measure this coefficient on a case-by-case basis.

5.5. Dilation

When an increasing shear stress is applied to a salt sample, the onset of dilation can be observed: (inelastic) volumetric strain rate becomes positive, a clear sign of the development of multiple micro-fractures. These micro-fractures are oriented in the direction of the most compressive stress. Onset of dilation is easier when the confining pressure is smaller. It is accepted widely that rock dilation is a relevant indicator of damage (Cristescu and Hunsche, 1998). Dilation generally is accompanied by a loss of material strength, a dramatic increase in permeability, and acoustic emission (Popp et al., 2012).

Various dilation criteria were proposed in the literature, Spiers et al. (1990), DeVries et al. (2006), Schultze (2007). The simplest criterion was fitted against tests performed on Gulf Coast salts by Van Sambeek et al. (1993): salt dilates when the Factor of Safety (FOS) is smaller than 1:

$$\mathrm{FOS} = \frac{0.27\left|I_1\right|}{\sqrt{J_2}}$$

I_1 is the first invariant of the stress tensor, and J_2 is the second invariant of the deviatoric stress tensor. In other words, in addition to hydraulic fracturing, a second mechanism may lead to permeability increase. Computations prove that this mechanism can be activated especially when cavern pressure is low. Whether the damage (permeability increase) resulting from dilation is cumulative or not (i.e., healing takes place when cavern pressure is high) is still a question open to discussion. For instance, Minkley et al. (2011), when defining the “penetration” zone, consider the dilation accumulated during the entire history — not only the damage created during the last cavern pressurization.

5.6. Observations performed on the Te02 cavern

Rousset and Hévin (2013) monitored a cavern that had been operated for over 8 years as a gas storage for 40 years. (The maximum pressure gradient was 16.6 kPa/m, or 0.734 kPa/m.), after which it was filled with brine. During its 40-year-long operating period, the cavern had shrunk by 60%, and it reasonably can be assumed that the salt had experienced damage at the cavern wall. The cavern is shut-in now. Brine pressure has increased gently due to brine warming and cavern creep closure. From time to time, brine is vented from the cavern, and gas is produced during venting. Whether this gas is released from traps or from a “damaged zone” at the cavern wall is still unclear, but it is not unreasonable to surmise that permeability increased at cavern wall, leading to some infiltration of gas in the rock mass.

5.7. Conclusions

The permeability of virgin salt is quite small. However, two mechanisms can lead to permeability increase at a cavern wall: dilation, and onset of tensile effective stresses. These mechanisms are activated by the state of stress at the cavern wall, which is a complex function of pressure history and results from several mechanisms: salt creep, elastic behavior and thermo-elastic behavior. These effects can be computed accurately [see, for instance, Nieland and Ratigan (2006), Dusterlöh and Lux (2010), Schreiner et al. (2010), Brouard et al. (2011), Karimi et al. (2011), Rokahr et al. (2011), Pellizzaro et al. (2011), Zapf (2014) and Zapf et al. (2011, 2013)]. It seems difficult to avoid the creation of a damaged or “impregnated” zone at the vicinity of the cavern wall. In such a zone, salt permeability is greater than when in the virgin state. Although research is still on-going, there are several reasons to believe that this permeability increase is not harmful:

- During rapid injection or withdrawal, mechanical (elastic) stresses and thermal stresses are generated. However, additional mechanical stresses are tensile when additional thermal stresses are compressive, and a kind of balance is achieved — at least when pressure swings are not too large.
- Hundreds of gas caverns were operated worldwide as gas storage caverns, and no gas leaks through the salt formation were reported.
- Thermal stresses play a significant role in the onset of tensile stresses. However, the zone at cavern wall in which tensile stresses develop is thin: the heat capacity of gas is low, and, even after a large depressurization, gas rapidly warms to reach thermal equilibrium again.
- When a long period of time (including several injections and withdrawals) is considered, *average* gas pressure is much smaller than its maximum pressure.

For these reasons, it is believed that no in-depth revision of the “empirical” approach is needed. It is strongly recommended, however, that computations be performed on a case-by-case basis when defining the cavern operating mode — and especially for the focus of this paper, the effects of the selected maximum pressure.

Conclusions

1. Selection of the maximum pressure in a gas-storage cavern must be based on assessment of the vertical stress, which can be computed readily using density logs. Frac tests also may be helpful, but they seem to provide an upper bound of the vertical stress.

2. The maximum operating pressure is 80-85% of the vertical stress. However, larger values can be considered, especially for newly developed caverns in a site where caverns have been operated successfully for several years and from which experience was gained. The specific case of the conversion of a brine cavern into a gas-storage cavern must be considered on a case-by-case basis.

3. Numerical computations must be performed to analyze the effects of the selected operating mode and to determine that they do not lead to unfavorable stress redistributions in the rock mass (when compared to the virgin-stress distribution).

4. Cavern tightness must be checked through an MIT performed at a pressure at least equal to the selected maximum pressure.

These conclusions are confirmed by decades of safe operation of hundreds of caverns.

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